Section 3: North American Gas Production

Introduction

Natural gas is produced in a number of regions, or basins, within North America. This section of the report provides a brief overview of the gas producing regions within Canada and the western United States, with primary emphasis on the two gas producing regions that currently supply the Northwest: the Western Canadian Sedimentary Basin (WCSB) of Alberta and British Columbia, Canada, and the Rocky Mountain region. Because the natural gas market has moved from numerous regional markets, to a more unified national market, a brief overview of other U.S. gas producing regions is included. A brief overview of the natural gas resources and production within Mexico is also presented. Gas producing regions in western North America are shown in Figure 3.1 on the next page.

Canadian Natural Gas Production

Much of the natural gas used in the Pacific Northwest comes from Canadian sources. Canadian production peaked at just over 17 billion cubic feet (Bcf) /day (6.6 Tcf/year) in 2001 and declined slightly to 16.7 Bcf/day in 2002.[1] Canada consumed nearly 8 Bcf/day in 2002, allowing exports of approximately 9 Bcf/day, or about 3.5 Tcf/year, to the United States. Most Canadian gas production and gas reserves are located in the WCSB, which is located primarily in Alberta, but also extends into eastern British Columbia, southwestern Saskatchewan, and a small portion of the Northwest Territories. Most of the Canadian natural gas that Washington State imports comes from the B.C. portion of the WCSB. The central part of the WCSB, primarily in Alberta, was developed first and should be considered a mature producing region with limited growth potential. The western most portion of the WCSB, located in British Columbia, was developed later, and has a higher reserve to production ratio (R/P) and larger field size, which means production growth potential still exists in this part of the WSCB. The gas resources developed thus far are nearly entirely conventional in nature. A large unconventional gas resource exists in the WSCB and will likely be developed in the near future.

Canadian gas exports to the United States rose steadily during the 1990s, from approximately 1.3 Tcf in 1990 to 3.6 Tcf in 2001, and represented nearly 17 percent of total U.S. gas consumption in 2001. Figure 3.2 below illustrates the steady increase in gas imports from Canada over the last 15 years. Note the recent leveling off of Canadian imports in 2001-02, and the slight decline in 2003. The EIA estimates that gas imports from Canada were down 12 percent in 2003 despite sustained high market prices. A portion of the 2003 decline in exports was probably due to the need for additional gas for storage within Canada following the large storage draw down during the winter of 2002-03.

[1] November 2003 production was estimated at 16.2 Bcf/day. Production estimates from Cambridge Energy Research Associates and Statistics Canada.

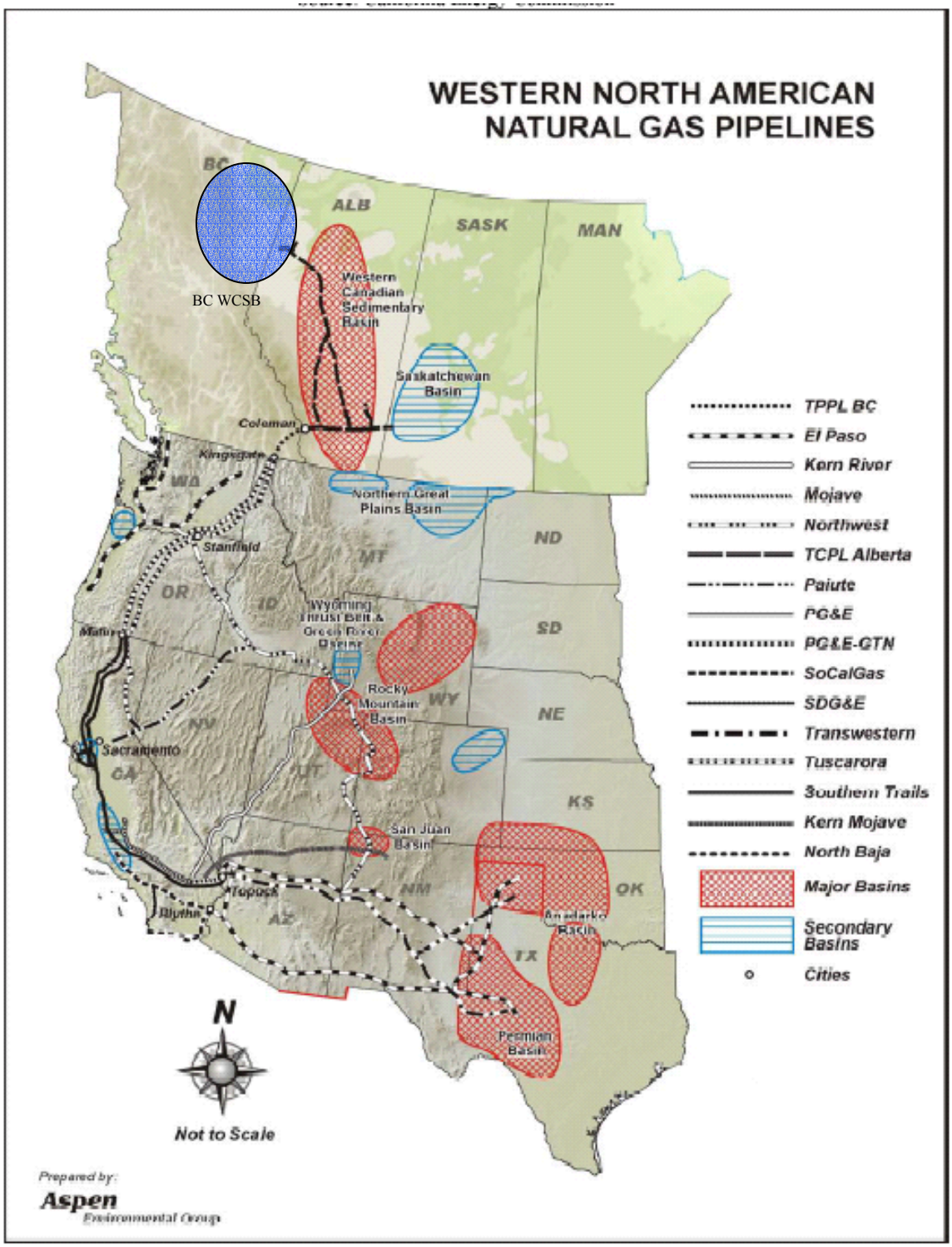

Figure 3.1: Western North American gas producing regions and pipelines.
Source CEC, 2003

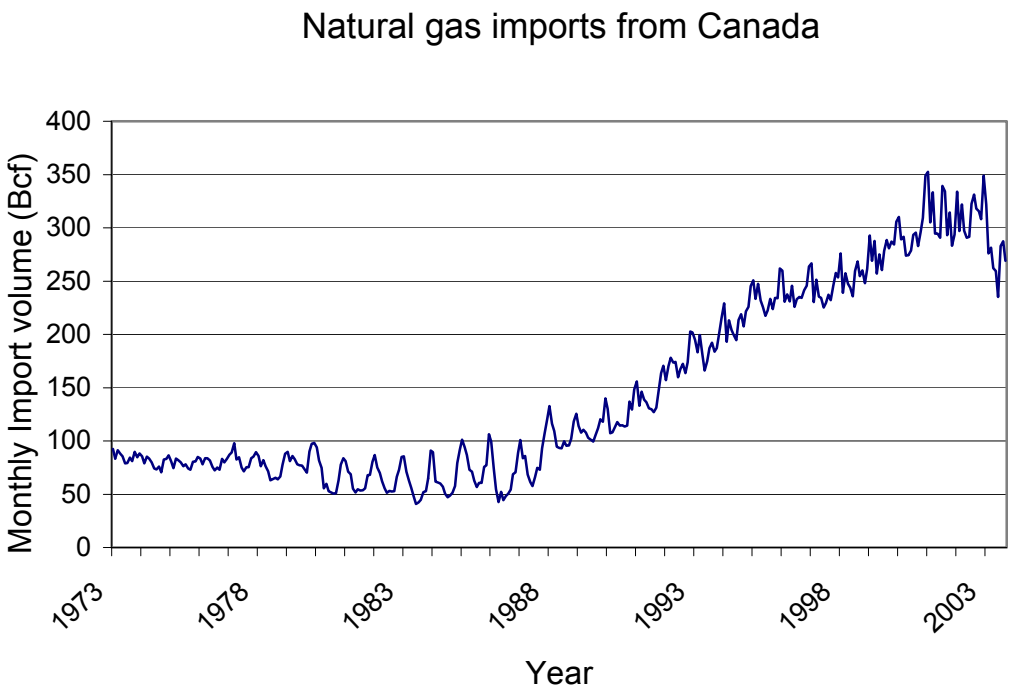

Figure 3.2: U.S. monthly imports of Canadian natural gas 1973-2003,
Source EIA.

The EIA, in its often cited 2001 natural gas report, forecast that over the next 20 years U.S. natural gas consumption would rise to 33.8 Tcf, and that imports from Canada would rise to 5.5 Tcf per year (15.1 Bcf/day). Relative to 2001 consumption, the 2020 forecasts represent a 57 percent increase in overall gas consumption and a 40 percent increase in imports of Canadian natural gas.

Recent assessments suggest that Canadian natural gas exports will not rise to the level cited in the 2001 EIA natural gas report. The Canadian Gas Potential Committee (CPGC) using recent sources of information, stated that conventional gas production from the WCSB will likely be peaking in the around 2005, and that unconventional and Arctic resources will probably only make up for the decline in Canadian conventional gas production (CGPC, 2001). The Alberta Energy and Utility Board reported that Alberta natural gas production (primarily from the WCSB, which represents 75 percent of total Canadian output) fell 3.8 percent in 2002, and predicted production would increase only 1.5 percent in 2003, as a result of the current drilling boom, remain stable in 2004, then fall at 2 percent per year through 2012 (AEUB, 2003). In a similar vein, a report by Thomas Driscoll, energy analyst for Lehman Brothers, states that 2001 may have been the high water mark for Canadian natural gas exports and that they will decline slightly from 9.7 in 2001 to 9.3 Bcf/day by 2005 (Energy Pulse, 2003).

The National Energy Board (NEB) recently forecast that natural gas production from the WCSB would decline slightly from 16.3 Bcf/day at the end of 2002 to 15.8 Bcf/day by the end of 2005 (NEB, 2003). The NEB cited the rapid decline rates and small field size

of newer gas wells as the major reasons for the forecast decline in production.[2] The NEB estimated that a record 14,400 gas wells were drilled in Canada during 2003 and that drilling would need to be maintained at 13,400 wells per year to keep production from declining further. The NEB forecast modest increases in Canadian gas production through 2010, to about 18 Bcf/day, followed by a gradual decline in production thereafter (NEB, 2003b).

The Canadian Energy Research Institute study forecast an increase in total Canadian gas production to 19.2 Bcf/day (7 Tcf/year) by 2010, but this was dependent on a near doubling of drilling activity, and a sizable contribution from unconventional gas sources, such as coal-bed methane (CERI, 2003). Cambridge Energy Research Associates (CERA) was also optimistic about Canadian production, forecasting that over the next several years increased drilling and unconventional resources would turn WSCB production around, possibly reaching 18 Bcf/day by 2010.

The Canadian gas industry has had several resource development disappointments over the last two years. Production from Ladyfern, the recent large gas play in northern British Columbia, has fallen by two-thirds from its mid 2002 peak, and will be an insignificant source in a few years. The Deep Panuke project off of Nova Scotia has been delayed because of disappointing exploratory wells. Development of the Mackenzie Delta resource is moving forward, but will take nearly five years to complete, and will only add modestly to Canadian production. Coal-bed methane, tight sands and deep well natural gas hold significant potential. However, to date unconventional resources have seen little development activity in Canada, largely because of high extraction and infrastructure costs. It will be several years before unconventional resources contribute significantly to Canadian gas production.

A number of factors might limit Canadian exports to the United States over the next five to 10 years. Stagnant production, growing demand within Canada for natural gas, and public opposition to gas exports, have the potential to reduce Canada gas exports. Demand for natural gas by the oil sand projects,[3] and the need to replace existing coal power plants to meet Canada's Kyoto protocol requirements are additional factors that could limit natural gas exports from Canada.[4]

Because of the above factors, it is likely that Canadian exports to the United States will be flat or decline incrementally over the next several years and then rebound slightly as natural gas from unconventional resources and Mackenzie Delta begins to enter the market around 2008. Because the short-term decline in Canadian exports is expected to be small, and since Washington State receives most of its gas from British Columbia,

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[2] The NEB estimated the overall decline rate for existing wells in the WCSB at 23 percent per year.

[3] Oil sand production currently consumes 300 to 400 MMcf/day and it is estimated that this will increase to at least 500 and possibly to 1,000 MMcf/day by 2010. Source: National Research Council Workshop on Natural Gas Supply and Demand 2003

[4] The Kyoto accord will put pressure on Canada to convert some of its 5,000 MW of coal fired electric capacity to natural gas to lower carbon dioxide emissions.

where production is forecast to grow over the next several years, the near-term impact on the state should be modest. After 2010, declines in Canadian exports are likely to resume as overall gas production plateaus and internal demand continues to grow. This could present a problem for consumers in Washington State if new supply sources are not brought to market in a timely manner: The EIA and the NPC forecast declines of 25-50 percent in Canadian imports by 2025.

Rocky Mountain Natural Gas Production

The Rocky Mountain region is an area of high current and potential natural gas production. Proved reserves are 35 Tcf and 2002 production was 1.9 Tcf. Production has risen steadily in the Rockies region, increasing by approximately 25 percent in the last five years alone. The EIA forecasts that gas production from this region will increase by 2.7 Tcf per year by 2020 (EIA, 2003). This region also contains approximately 35 percent (293 Tcf) of the remaining undiscovered technically recoverable natural gas in the Lower 48 onshore United States. Most of the Rocky Mountain resources are *unconventional*: 65 percent in tight sand formations, and 16 percent classified as coal-bed methane (EIA, 2001b). Environmental and other constraints currently limit access to about 45 percent of the resource.[5] Efficient development of the resource is further restricted by the complex nature of the reservoirs found in the Rocky Mountain basins that require special geological characterization, drilling, and production techniques to become economically feasible to produce. In addition, the U.S Environmental Protection Agency (EPA) and U.S. Bureau of Land Management (BLM) have recently developed stricter requirements for the disposal of process water and land use, which will add to the cost of resource development in the Rocky Mountain basins.

Despite the challenge of extracting the gas resource it is anticipated that production will continue to increase in the Rocky Mountain region. However, due to resource access restrictions and environmental concerns, the increase in production forecast by the EIA (production of 4.5 Tcf per year in 2020) may be optimistic.

Gas Production In Other Basins

Although Washington State receives the bulk of its natural gas from Canada and the Rocky Mountain basins, production from other regions is also of interest due to the increasingly integrated nature of the North American natural gas market. Most of the gas producing regions are located in the south central part of the nation and are in general mature highly developed resources. Figure 3.3 below illustrates the gas production in a number of regions within the United States.

[5] The Rocky Mountain resource volumes under access restrictions are consistent with the findings of the 2003 National Petroleum Council natural gas resource study, which found that 40 percent of the natural gas resource located in the Rockies, is either closed to exploration or faces severe restrictions on development.

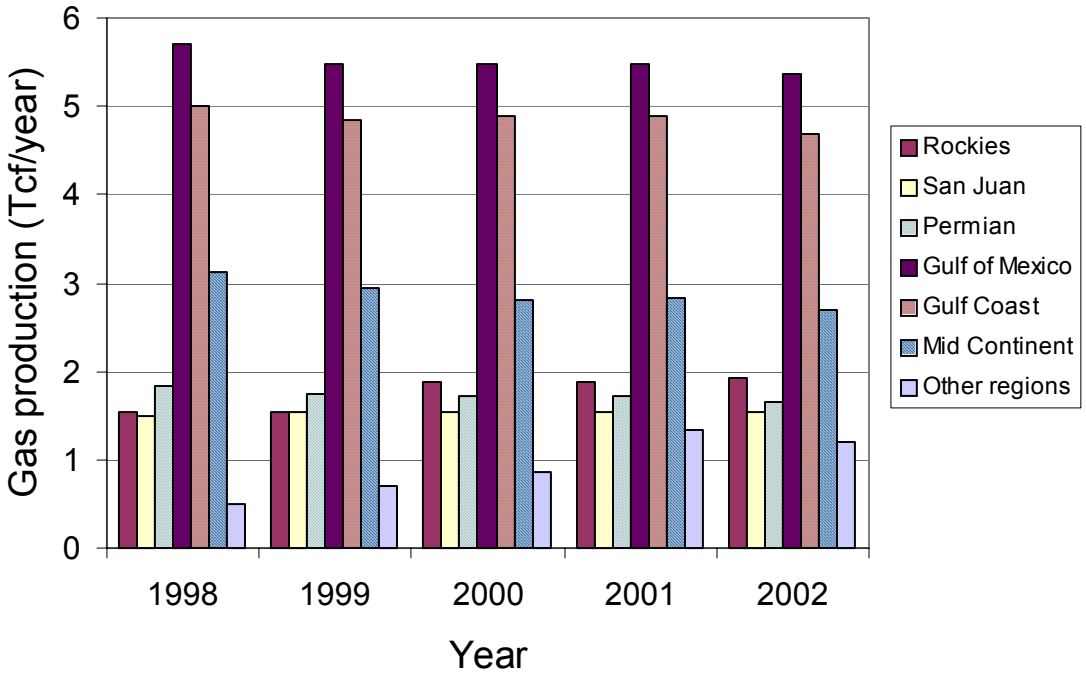

Figure 3.3: Natural gas production by region
Source CERA and EIA.

The category designated *other regions* is the combined production from smaller natural gas basins such as California, Upper Great Plains, Alaska, and Appalachia. The figure above reveals that during 1998–2002 production in the Gulf of Mexico, Gulf Coast, Mid Continent, and the Permian basin was declining, while production was holding steady in the San Juan basin. The Rocky Mountain basin and the smaller producing regions (*other regions*) showed some production growth during the period. Over the last several years U.S. natural gas production has held at roughly 19 Tcf per year.

As the Figure 3.3 above indicates, the Gulf of Mexico (GOM) is the nation's most important gas producing region contributing approximately 25 percent of U.S. gas production, or about 5 Tcf per year. Estimated reserves and undiscovered resources for the GOM are 56 Tcf. Recent deep-water discoveries (water depth greater than 1,500 feet and total depth more than 15,000 feet) have made up for declining discoveries and production from the shallow water Gulf. Figure 3.4 illustrates recent GOM gas production and the rapid rise in production from deep-water wells.

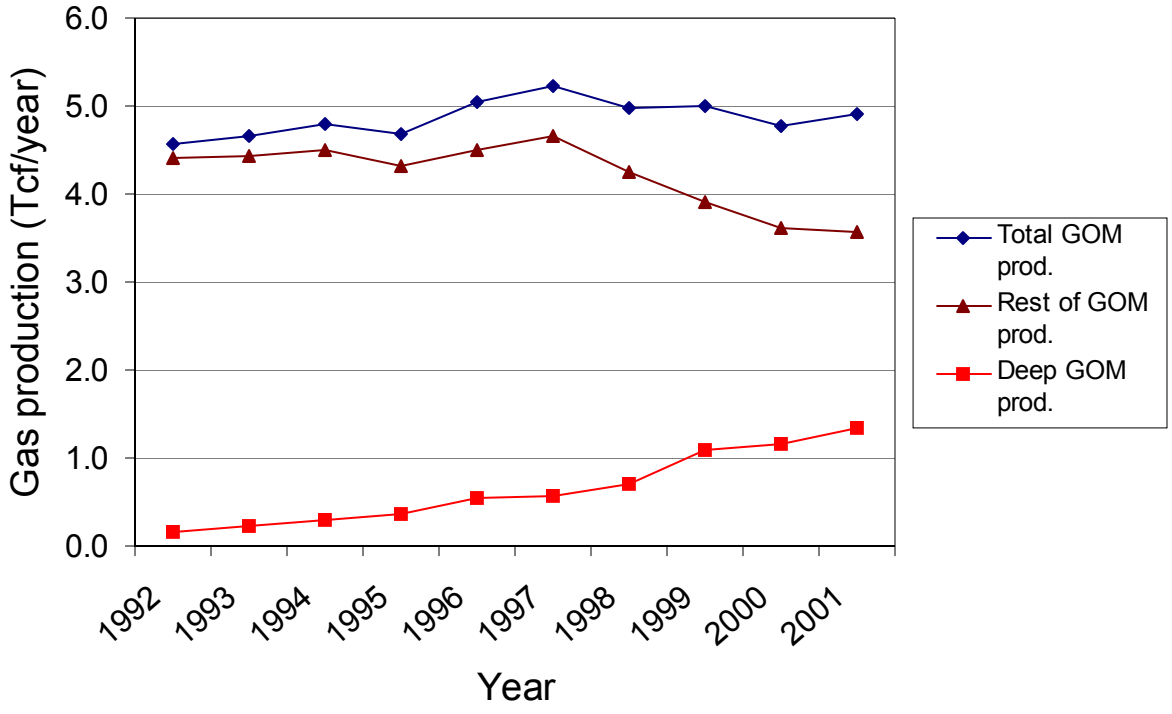

Figure 3.4: Gulf of Mexico production 1992-2001

Source: Michelle Michot-Foss testimony 2003.

Figure 3.4 illustrates how increasing production from deep-water GOM fields is just offsetting the decline in the rest of the GOM. Deep water drilling is much more expensive[6] and carries a higher risk penalty. Drilling for gas via ultra deep wells (total depth more than 15,000 feet) in the declining shallow water basins of the GOM appears to hold some promise, but is also expensive and risky. Over the next 10 years, only slight net additions to production from the GOM region are anticipated.

Mexican Production

Mexican natural gas production reached 1.75 Tcf in 1999, and has declined slightly over the last three years to 1.62 Tcf in 2002. Restructuring and privatization are taking place in parts of the natural gas industry and natural gas use in electricity generation and manufacturing has been encouraged. Demand for natural gas in the power generation and industrial sector has been forecast to grow by 14 percent annually (Alexander, 2002). Total Mexican gas demand is projected to grow 50 percent to 2.4 Tcf per year by 2010, and by 100 percent to 3.2 Tcf per year by 2015.

Mexican gas production and consumption is of importance to the Northwest, because Mexico has been unable to meet its internal natural gas requirements and has had to

[6] Average onshore drilling cost per well 0.5 million dollars; average deepwater well drilling cost 10 million dollars.

import increasing quantities of natural gas from the United States. The imported gas is primarily used to supply manufacturing facilities along the U.S. and Mexican border, and for electric power generation, some of which is sent north to U.S. consumers. The gas that Mexico imports is principally produced in Texas or New Mexico and is part of the resource available to California. A reduction in availability of this gas resource puts additional pressure on gas supply resources for California, including gas from the Rocky Mountain and Canadian regions. Indirectly, gas exports to Mexico put modest upward price pressure on gas resources supplying the Northwest. Near term projections are that exports to Mexico will continue to increase for several more years, reaching 750 Bcf/year in 2007 before liquefied natural gas (LNG) imports and Mexican production begin to fill market demand. Figure 3.5 below presents the U.S. natural gas exports from 1990 to 2002.

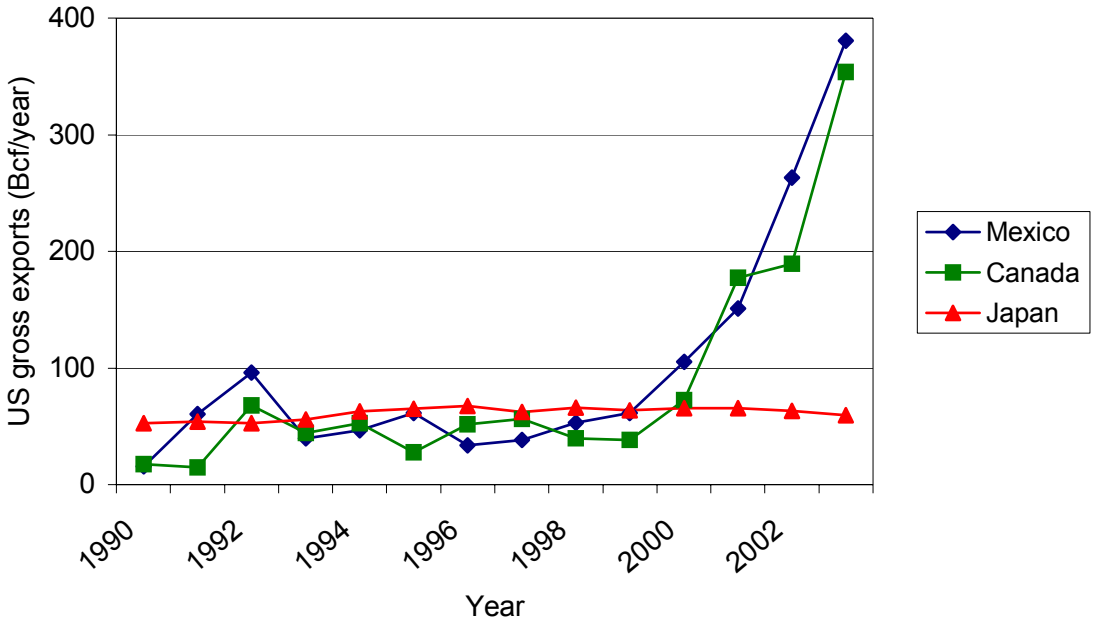

Figure 3.5: U.S. natural gas exports 1990-2002
Source: EIA.

As Figure 3.5 illustrates natural gas exports to Mexico and Canada have risen rapidly in recent years. Note that exports from Canada to the United States are more than an order of magnitude larger than exports from the United States to Canada. LNG exports to Japan via Alaska have been fairly steady at 60 Bcf/year. Though gas exports to Mexico are not yet significant (less than 2 percent of U.S. consumption), continued growth over the next several years could put additional upward pressure on U.S. natural gas prices. Because of Mexico's rapidly growing need for natural gas, several LNG projects have been proposed for Baja California and the Gulf of Mexico and are in the early stages of development.

Production from a Mature Resource Base

North American natural gas production and consumption grew rapidly from the late 1980s as the economy expanded and deregulation continued. By the late 1990s production growth had slowed as the excess productive capacity, developed primarily during the 1980s, was slowly eroded. For the last six or seven years U.S. producers have essentially run flat out all year round. See Figure 3.6 below.

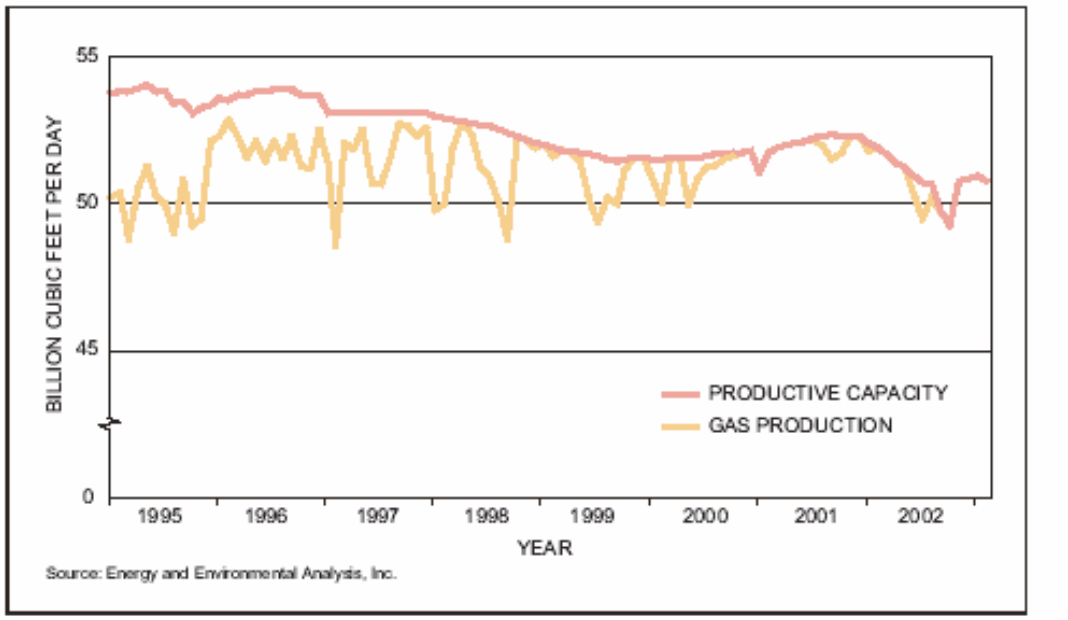

Figure 3.6: Lower 48 production versus productive capacity

Source NPC 2003

U.S. production peaked in 2001 following a ramp up in drilling that was induced by the high natural gas prices of 2000-01. A significant decline in drilling and a slight decline in gas production followed the natural gas price collapse of 2002. Decreasing recovery volumes and productivity per gas well, has meant that more wells have to be drilled every year just to keep production steady. Figure 3.7 below illustrates the decreasing average well productivity in the United States and the increasing number of active wells necessary to maintain or grow production. The addition over the last 10 years of progressively more gas wells with rapid decline rates (small gas fields) has increased the overall base decline rate of the North American gas resource from 17 percent per year in 1992 to 27 percent per year in 2001.[7] The NPC anticipates an average of nearly 20,000 gas well connections will have to be made each year from 2005 to 2020 just to maintain current production. The average number of new gas connections from 1986 to 1997 was only 6,950 per year.

[7] The increase in the base decline rate has been even more dramatic in Canada.

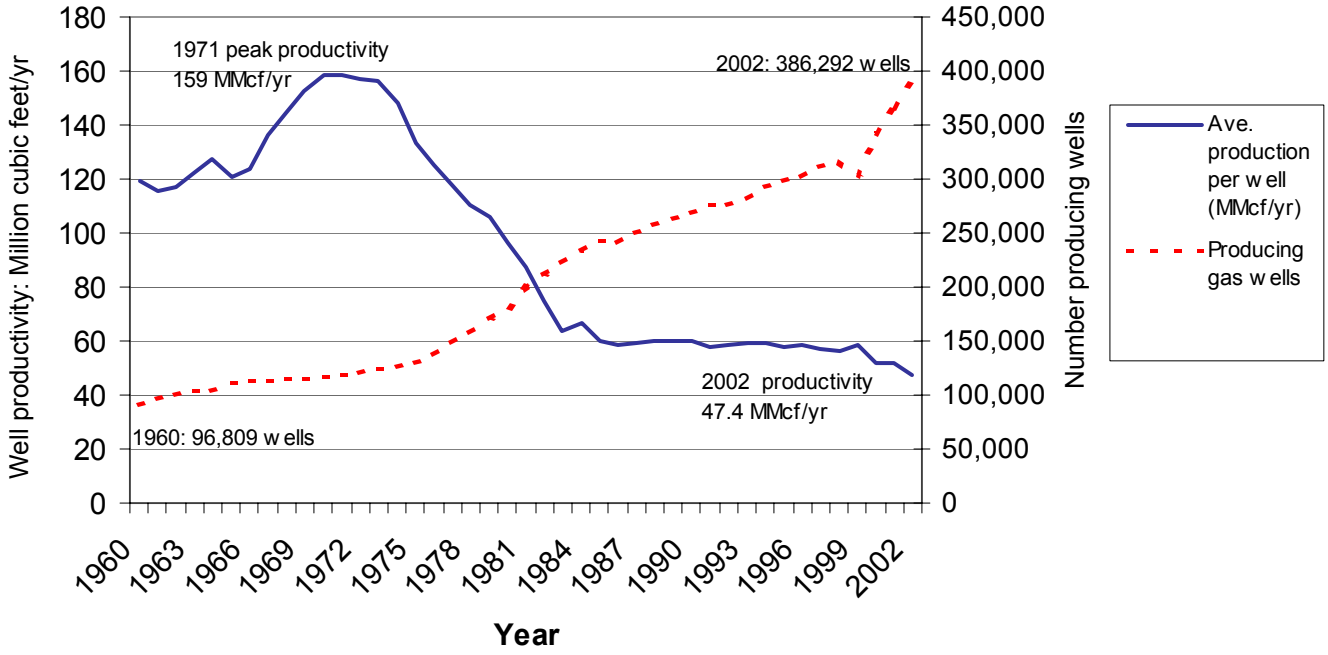

Figure 3.7: Number of producing wells in the United States and average productivity
Source: EIA.

As recently as three years ago the EIA and NPC forecast that significant new gas resources and productive capacity could be developed in the United States and Canada in response to small increases in gas wellhead prices. However, decreasing well recovery volumes (see Figure 2.2), reduced reserve appreciation factors, and a weak production response following the drilling boom of 2000-01 has caused both the NPC and EIA to reevaluated the future productivity of the U.S. Lower 48 and the Canadian natural gas resource.

The NPC now forecasts significantly higher prices and flat production through 2020 for the U.S. Lower 48 and non-Arctic Canada. Production from conventional gas basins will continue to decline, and will be offset by increases in production from unconventional gas resources. The EIA forecasts slightly lower prices and a small production increase for the U.S. Lower 48 and non-Arctic Canada through 2020.

Both the NPC and EIA now acknowledge that traditional resources, which include some unconventional gas resources, will not be able to meet the forecast increase in North American gas demand. New resources (and production) such as Arctic natural gas and LNG are included in sizable quantities in the newest NPC and EIA forecasts.

Summary

A review of production assessments and forecasts by the EIA, NPC and others allow us to make the following observations.

1. Canadian production after rising rapidly in the 1990s to 6.6 Tcf per year, appears to have reached a plateau and is unlikely to grow prior to the large-scale development of Arctic and unconventional gas resources.
2. Due to increasing internal natural gas consumption Canadian exports to the United States will be flat over the next five years and will likely decline after 2010.
3. Natural gas production from the Rocky Mountain basins is forecast to increase to 4.5 Tcf per year by 2020. While this resource is relatively close, the Pacific Northwest will have to compete with other gas consuming regions.
4. Most other gas producing regions in the United States have recently shown flat or slight declines in production. The deepwater region of the Gulf of Mexico is forecast to show a small production increase over the next five to 10 years.
5. Mexico has been unable to meet its growing natural gas demand and is importing increasing quantities from the United States. This puts additional pressure on gas markets in the U.S. Southwest.

The gas producing basins in the U.S. Lower 48 and Canada (excluding Arctic and Rocky Mountain regions) are mature and cannot meet the growing North American demand for natural gas. New resources will be necessary to meet growing